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Modeling and control of HVDC grids: a key challenge for the future power system

(Survey Paper)

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***Abstract*—HVDC technology is developing fast and HVDC grids are increasingly seen as a possible and feasible solution to manage the future power system with large amounts of renewables in a secure and cost-effective manner. However, systems with significant amounts of DC transmission behave in a fundamentally different manner when compared to the traditional AC power system. The integration of HVDC systems introduces new fast dynamics on different time frames and adds controllability to the combined system. As a result, the modeling and control of the entire interconnected system needs to be re-evaluated in order to accurately compute the system behavior, both from the AC and DC system.**

This survey paper gives an overview of the current research in the field of HVDC grids focusing on the interaction of the AC and DC system. The converters and their behavior are discussed in greater detail. A second component which is discussed is the DC breaker. Both devices operate fundamentally different than their AC counterparts. The fast interaction between AC and DC systems requires changes in the manner in which the modeling and computation of the system is done, both at the DC and the AC side. Although these considerations are needed within all relevant time frames, two relevant cases are specifically addressed in this paper: the connection of offshore wind power through a HVDC system and the optimal operation of the power system with a strong presence of HVDC.

***Index Terms*—HVDC, HVDC grid, power system dynamics, power system operations, offshore wind farms, OPF**

I. Introduction

The electric power system is changing through the introduction of new components which fundamentally change the behavior of the power system. HVDC technology is one of these new components. HVDC is seen as an enabler for a future power system that is sustainable and reliable and which provides a cost-effective and competitive energy supply. Although HVDC has existed for over 50 years, recent developments in power electronics have created new opportunities. HVDC grids are expected to bring higher transmission capacities for longer distances and are especially interesting if cable connections are considered [1]. They are also specifically interesting when connecting large offshore energy resources.

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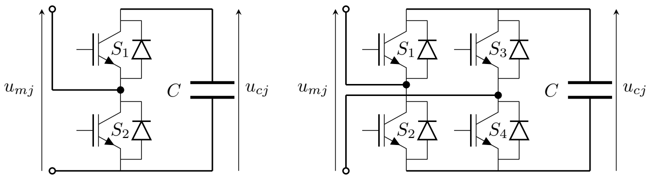
Over recent years, significant research has been performed in the field of HVDC and HVDC grids. This paper looks at the integration of HVDC grids in the different modeling time frames of power system calculation, highlighting the first conclusions that have been reached and the remaining challenges from a modeling perspective. Throughout the paper, the perspective of the hybrid AC/DC power system is kept. Tuning of the very dynamic controllers is an issue in itself which is quite extensively addressed in literature and has been left out of the scope of this paper.

The analysis starts first with a description of the HVDC technology for grids. Each of the components contributes to the system behavior, depending on the characteristics of that component and its limitations. The focus lies on the converter, more specifically the Modular Multilevel Converter (MMC). As the converter forms the interface between the AC and DC system, the manner in which it is controlled forms an essential aspect of the interaction, most importantly in managing the energy balance between AC and DC system. Also the status of the DC breaker is discussed as it was long seen as the Achilles heel of DC grids. Both the converter and the breaker behave fundamentally differently compared to standard power system equipment, introducing different dynamics.

In a second part, the modeling challenges associated with the introduction of new components on the different time frames are discussed. The interaction between different components influences the modeling detail, also of existing equipment in the AC system. These new models in turn also influence the manner in which power system computations are done.

The integration of HVDC and HVDC grids in the power system requires special attention in considering how the system is modeled for all aspects of the power system, from the fast transients to the planning stages. The third part of the paper focuses on two applications where this influence is shown. The first application is the connection of offshore wind power plants to a VSC HVDC converter station. The changes in the manner in which the hybrid AC/DC system is operated is treated as a second application. Modeling the hybrid AC/DC system to ensure an optimal and secure operation is given as an example.



(a) Half-bridge switch (b) Full-bridge switch

Fig. 1: Half-bridge and full-bridge sub-modules of MMC converters

II. AC/DC CONVERTERS FOR HVDC APPLICATIONS

A. Power electronics in power system applications

The development of power electronics has been ongoing for a very long time. One major event was the development of the Insulated Gate Bipolar Transistor (IGBT) for industrial applications in the nineties: a very powerful transistor much easier to drive than the older bipolar transistor and more flexible than the older thyristor. .

The first applications were variable speed drives for electrical machines: from very small power to high power multi megawatt propulsion for ships. The power electronic topologies for these devices are very well known: 2-level converters and occasionally 3-level converters. The increase of renewable energy sources has increased the use of power electronic converters significantly, but most of the power electronic applications employed the classical topologies. The real breakthrough came from the use of extra high power converters in the transmission system, which required the invention of new topologies.

The use of power electronics in transmission systems is not a new idea since it has been used for decades, but mostly with thyristor components. The first thyristor-based link was built in the early seventies for the Eel River project (2× 80 MW). Capacity rose quickly (e.g. the IFA 2000 France-UK link was built in 1986 with a power capability of 2 GW). The capacity of the newest thyristor based links installed in 2013 exceeds 7 GW. Transistors have also been used in HVDC applications for about 15 years, with the first installation on the Island of Gotland at the end of the previous century. These first installations used "simple" 2-level converters. The Cross Sound Cable (330 MW, 150 kV) between Long Island and the American continent was installed in 2002 using a 3-level converter. Because of the high voltage levels, a very large number of transistors is placed in series. However, this large stack of series switches needs to have nearly identical parameters and synchronized ignition to avoid excessive stresses on single components during switching actions. The high frequency switching operation of the PWM ($\approx$ 1 kHz) was also responsible for significant losses in the range of 3 % per converter for the first generation down to 1.4 % per converter for the 3rd generation PWM based converters [2].

The Modular Multilevel Converter has been developed to overcome the aforementioned problems. Indeed, it is not an evolution of the classical converter, but a new topology. This new topology has been known conceptually for quite a long time but the technology was not available to achieve such a complex topology for transmission system applications. The MMC converter is built up using either half-bridge or full-bridge sub-modules. The half-bridge element is the most commonly used element as it is cheaper and causes lower losses. However, the full-bridge element has the ability to completely block the converter current, also during DC faults. Throughout this work, half-bridge sub-modules are considered unless otherwise stated. A comparison and overview of alternative converter designs can be found in [3]. The first HVDC link using MMC technology is the Trans Bay link (400 MW, voltage ± 200 kV), installed in San Francisco in 2012. Two parallel 1 GW ± 320 kV links are being installed between France and Spain, becoming the largest VSC HVDC system. Two recently completed VSC HVDC projects connecting offshore renewables are the Helwin 1 and the Borwin 2 systems of resp. 565 and 800 MW which connect the German mainland with offshore wind farms in the North Sea.

B. Switching components

HVDC systems are developed using both the traditional thyristors and IGBTs.

The use of IGBTs instead of thyristors has several advantages:

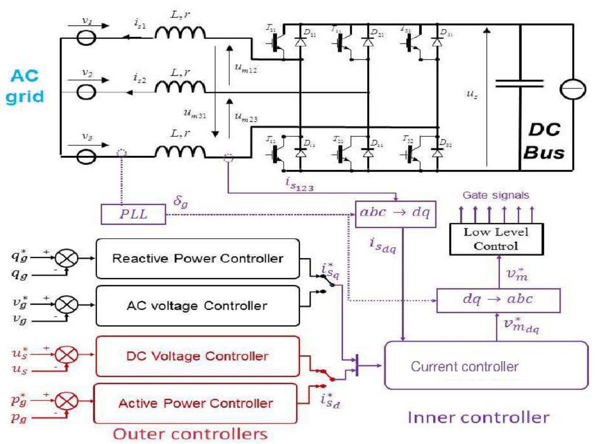
- the power control is much faster;
- it is possible to sink and source reactive power, which is not possible when using a thyristor based converter;
- the dynamic behavior allows AC fault ride-through;
- the power station footprint is smaller: there is no need to filter harmonics or compensate reactive power;
- the grid to connect a VSC HVDC converter to can be of low short circuit power. It is even possible to generate a grid after a blackout with such converters.

Of course, there are some drawbacks:

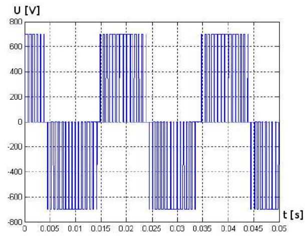
- the efficiency is lower, even although the gap is very small with the new MMC topology (0.7-0.8 % losses per converter at nominal load for thyristors based systems compared to 1 % for the newest VSC HVDC systems [2]);
- the cost is in general slightly higher;
- The main drawback is that limiting the DC current during DC faults is more complex. The thyristor converter behaves as a current source which leads to a natural limitation in case of fault whereas the currently used transistor-based variant behaves as a voltage source. Full-bridge sub-modules might provide a partial solution as they can limit the infeed.

C. 2-level VSC converter topology

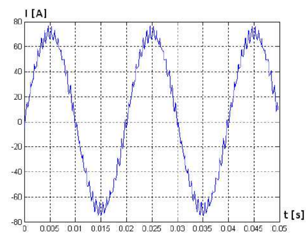
The "classical" or 2-level VSC topology is presented in Fig. 2. A sinusoidal duty cycle is applied to the gate of the transistor which induces a sinusoidal modulation of the DC bus applied to the AC system as shown in Fig. 2b.



(a) Topology and control



(b) AC modulated line-to-line voltage



(c) AC current

Fig. 2: Voltage Source Converter using 2-level topology

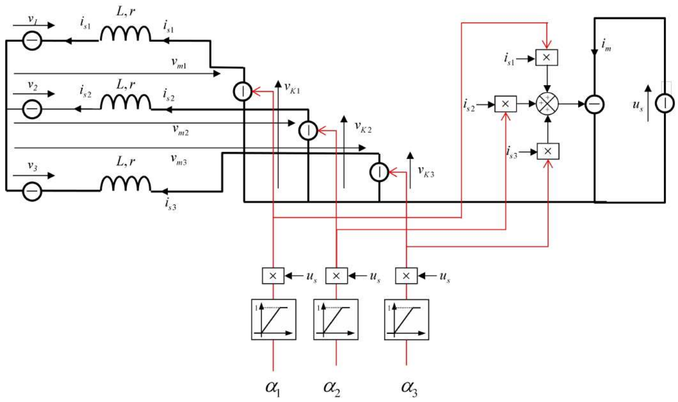


Fig. 3: Averaged model of a VSC

The inductance (phase reactor) allows power flow control and filters harmonics generated by the voltage modulation. Due to the high switching frequency and the low pass behavior of the filter, the current and voltage at the point of common coupling are quasi sinusoidal.

The energy stored in the inductance is negligible compared to the energy stored in the DC capacitor. Similar to rotating machines in an AC system, an inertia constant H can be defined for the DC system:

$$H = \frac{\frac{1}{2} \cdot C \cdot u_{sn}^2}{P_n} \tag{1}$$

with C the capacitance value, u_{sn} the nominal DC bus voltage and P_n the rated power of the converter.

The H value of a converter linked to the energy stored in the capacitive elements in the system ranges from 10 ms to several tens of milliseconds, much less than a mechanical inertia constant in AC systems (which is in the order of seconds). This results in a much faster dynamic behavior compared to traditional AC equipment. This requires very fast control actions performed by the converters and consequentially, any sudden change can result in very large deviations in a short time frame.

The fast controls of the VSC converter consists in part of a current loop, normally implemented in the dq-frame, and with a response time of 10 ms or lower, gives a current source characteristic to the VSC. This control loop acts as the inner controller. Around that controller, the converter is normally equipped with an outer controller which includes either a reactive or an AC voltage control and a DC voltage or active power control. As a convention, these controllers use respectively the d-axis and the q-axis values. The response time of these loops is about 100 ms or even lower. As pointed out previously, the response time of a power electronic converter is much faster than the classical response time of the typical electromechanical system found in the power system. The control algorithm is developed based on an averaged model as presented in Fig. 3.

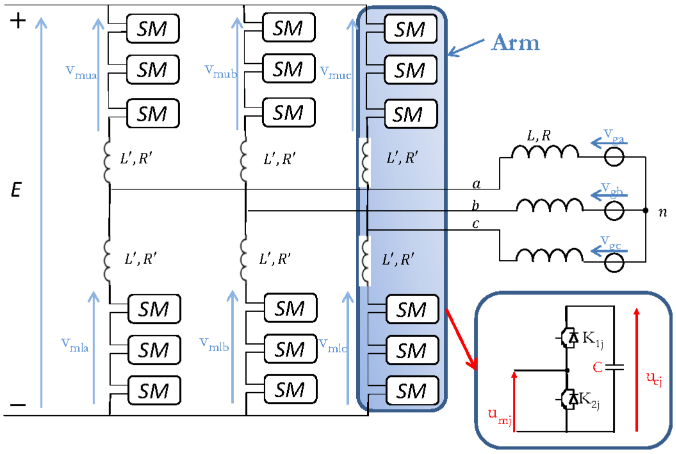
The averaged model represents the modulated (switched) voltage as its mean value during a switching time interval. The modulated current (i_m) is obtained by maintaining the power balance.

D. MMC topology

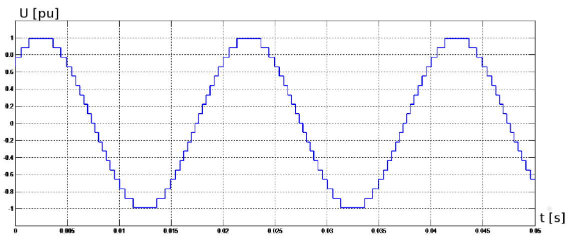
There are different designs of MMC converters. As mentioned earlier, only the topology with "half-bridge submodule" is presented in greater detail in this paper (see Fig. 1a). Currently, it is still the only one used in practice.

Depending on the control applied to the transistors in a module, the voltage u_{mj} is either zero or equal to the DC bus voltage u_{cj}. When connected in series and adequately controlled, the addition of all these elementary voltages generates a quasi sinusoidal with as many steps as the number of submodules (Fig. 4). Currently, the number of modules in series is several hundreds as single IGBTs can withstand less than 5 kV. In other words, the generated sinusoidal is nearly perfect so no or a very little harmonic filter is needed. The L' (and R') in the arms are sized (among other aspects) to limit the derivative of the current in case of short circuit on the DC bus. The total energy stored is in the same range as for the 2-level VSC, however, different implementations can lead to higher capacitance values for MMC applications.

Other implementations exist as well, for instance the cascaded 2-level converter which builds the voltage using fewer modules, in which each module contains a number of series-connected switches [4]. Another concept is the series hybrid circuit where a number of full bridge converters are placed in series with series IGBT valves [5].



(a) Topology: each sub-module "SM" is a half-bridge or full-bridge element



(b) Waveform

Fig. 4: Modular Multilevel Converter

In term of control, two different levels have to be distinguished. The low level control is in charge of balancing the voltage of the sub-module. To generate a given voltage, there are several of degrees of freedom in selecting the sub-modules to participate in forming the AC voltage [6]–[9]. Different approaches and modulation strategies have been proposed. However other functions internal to the power electronic converter are also needed to ensure the correct operation of the more complex MMC topology such as circulating current control and sub-module voltage balancing. The design of the higher level of the control is based on a simplified model. The outer control needs to be designed so that it at least does not strongly interact with this inner control, introducing possible additional constraints. To represent the energy stored the half arms, an equivalent model is used for each of them [10]–[12]. The voltage $u_{c,tot}$ is defined as the sum of the voltages for each capacitor of the same half arm.

$$u_{c,tot} = \sum_{i=1}^{N} u_{ci} \tag{2}$$

N: number of sub-modules (SM) in the same half arm.

It is possible to write:

$$C \cdot \frac{du_{c,tot}}{dt} = \underbrace{\sum_{i=1}^{n} C \cdot \frac{du_{c,i}}{dt}}_{\text{n active SM}} + \underbrace{\sum_{i=n+1}^{N} C \cdot \frac{du_{c,i}}{dt}}_{\text{N-n inactive SM}} \tag{3}$$

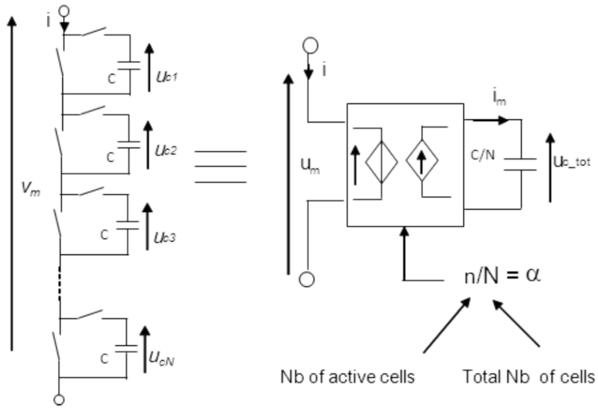


Fig. 5: Equivalent model of half a arm

This results in:

$$C \cdot \frac{du_{c,tot}}{dt} = n \cdot i \tag{4}$$

or:

$$\frac{C}{N} \cdot \frac{du_{c,tot}}{dt} = \frac{n}{N} \cdot i = i_m \tag{5}$$

Assuming that all the voltages are balanced, it is possible to write:

$$u_m = \frac{n}{N} \cdot u_{c,tot} \tag{6}$$

It is then possible to derive the equivalent model for a half arm of a converter as shown in Fig. 5 and a control methodology for the whole structure. This model enhances an important characteristic for this topology. The energy is not located in the same place as in the classical VSC. Indeed, the storage element is not connected directly to the DC bus. This can have important consequences in terms of managing the energy.

E. DC voltage control

In traditional AC systems, the balance (or rather unbalance) of power is seen in the frequency and managed through the power frequency regulation, often organized in a primary, secondary and tertiary control. One of the elements concerning HVDC grid which has received much attention is the management of the power balance at the DC side. As in any system, the DC system needs to maintain its power balance for a stable operation. Unbalances in the DC system are compensated by the energy storage in the DC grid, mainly in the form of its capacitance, causing a deviation of the voltage profile from the initial point. As such, the DC voltage behaves as a measure for the DC power balance, similar to the frequency is in an AC system. An important difference is the voltage drop in the DC system which causes different voltage set-points over the different DC nodes, contrary to the similar AC case where frequency is quasi constant throughout the system.

As stipulated in section II on converter modeling, the time constant of this behavior is much smaller, resulting in a much faster response. As such, the manner in which the voltage at the DC side is controlled is important for the stability of the

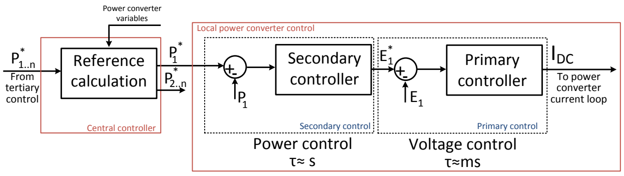


Fig. 6: Primary, secondary and tertiary control in a DC converter [15]

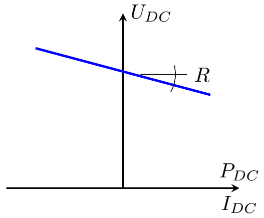
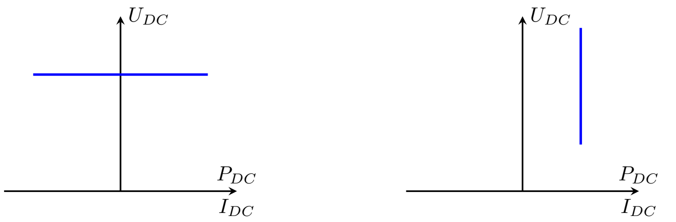


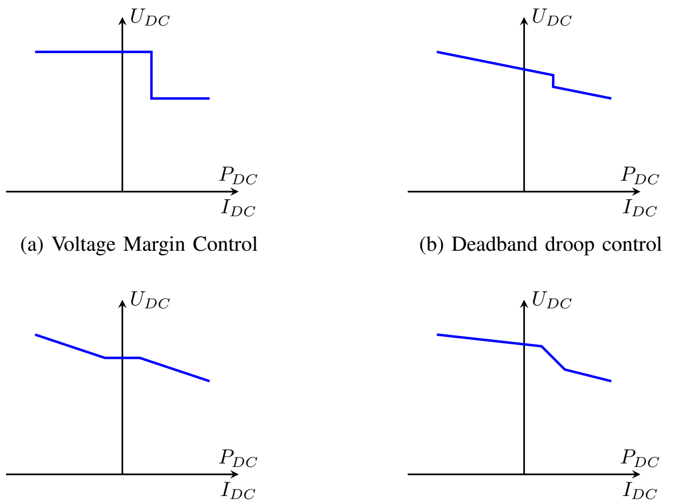
Fig. 8: Droop control: principle



(a) Constant voltage (slack)

(b) Constant power injection

Fig. 7: Master and slave control



(a) Voltage Margin Control

(b) Deadband droop control

(c) Droop control with voltage deadband

(d) Piecewise linear droop control

Fig. 9: Possible extended control concepts

HVDC grid. This reaction is possible through fast controls of the converter stations. Several academic studies have been conducted on this issue (for an overview see [13] and its references) and Cigré working group B4-58 [14] is preparing a technical brochure covering the topic.

The most basic mode of operation is a master-slave principle, where all converters set their power injection and one (slack) node fixes the voltage in the slack node (Fig. 7a and 7b). Such a system works well for smaller systems, but has the disadvantage that in case of the outage of the slack converter, a new slack needs to be assigned. A second disadvantage is that this slack converter takes all the "burden" and subsequently AC and DC systems can experience significant shifts in power flows when a large converter outage occurs.[1]

An alternative implementation is for all converters to collaborate and share the burden. This can be done by applying a "distributed slack" or "droop" control (see Fig. 8). This controller adjusts the power injection in a proportional manner in case an unbalance occurs.

The droop control has the advantage of sharing the consequences of deviations and limiting the individual contribution. On the other hand, the exact converter output will fluctuate with varying input. Furthermore, not all systems are able to provide a controllable varying power contribution, for instance when an offshore wind farm is connected to the HVDC grid. Such systems are usually controlled using a voltage independent power injection. In general, the droop of the individual converters can be different throughout the HVDC grid.

Several alternative methods have been proposed in literature which are adaptations of the aforementioned methods, for instance through the use of a deadband in either voltage or power (current) control. Fig. 9 shows some of these example implementations.

The figures of the voltage control methods in practice need to be coordinated with the necessary limits in converter capabilities. These limits can be both technology or grid code related.

In a practical future HVDC grid, multiple voltage control methodologies can co-exist in the same system, possibly through different implementations by different manufacturers or depending on the AC system it connects to. Correctly modeling them is needed to understand the interaction between DC grid, converters and AC grid.

The aforementioned control behaves largely as the primary control method in AC systems. Also for the secondary and tertiary response, similar control systems can be formed, which in turn influence the existing control mechanisms in the AC systems they connect to (Fig. 10, [15]).

III. DC BREAKERS

Protecting the HVDC system against short circuits at the DC side is specifically difficult for HVDC systems using converters which use 2-level or MMC converters equipped

[1] Although reference is made to voltage-power control, the mechanisms can also be implemented voltage-current control. As $P_{DC} = U_{DC} \cdot I_{DC}$ and the DC voltage is remains close to 1 p.u., the effect is rather small.

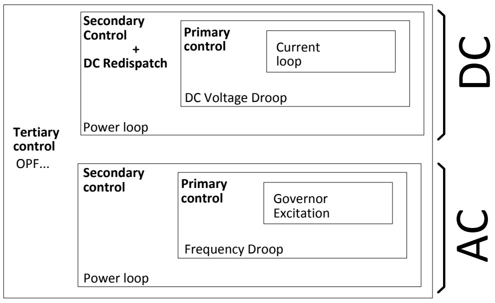


Fig. 10: Combined AC and DC control actions [15]

with half-bridge cells (see Fig. 1a). These converters contain IGBT switches with free-wheeling diodes in anti-parallel. When a DC short circuit occurs, the IGBTs can be blocked, but a parallel conducting path will be formed through the diodes, rendering the converter into an uncontrolled rectifier. The DC short circuit will be fed through all converters and the current is only limited by the AC and DC system impedance. As a result, the current rise at the DC side is very high and the DC current needs to be interrupted within a very short time period (an often cited value is 5 ms [16]). In current VSC HVDC schemes, this problem is addressed by utilizing a high impedance grounding system (symmetrical monopole [17]) which limits the short circuit fault for pole to ground faults and the AC protection system is then used to de-energize the entire DC system. In HVDC grids, de-energizing the entire HVDC grid is likely not acceptable and alternative measures are needed [18].

The unavailability of an HVDC breaker has long been considered to be the main hurdle for the development of HVDC grids using VSC HVDC, but recent developments by manufacturers have shown that such devices are feasible [19], [20].

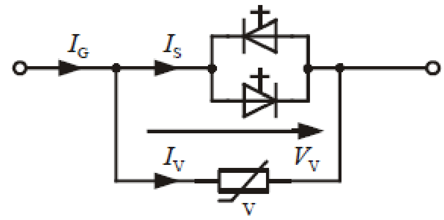
The functions that the DC breaker must fulfill can be split up as [21]:

- Create an opposing voltage to bring the fault current to zero;
- Dissipate the energy stored in the inductance and capacitance of the system;
- Withstand the overvoltages due to the interruption.

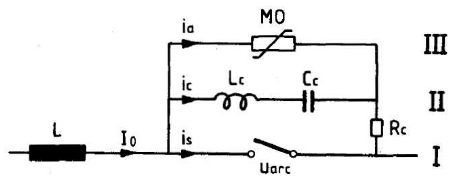
The first requirement is specific for DC systems since in AC systems, there is a natural zero crossing of the current at twice the fundamental frequency. With mechanical AC breakers, an arc that dissipates the energy in the circuit is drawn between moving contacts. When the arc is extinguished (either at a natural zero crossing or by forced extinguishing), the distance between the contacts provides isolation of the faulted area and the energized system. The speed of the breaker is typically expressed as the number of cycles of the fundamental frequency needed to interrupt the current.

For interruption of DC currents on the contrary, this approach is not possible as there is no natural zero crossing of the current and an arc remains between the contacts. Therefore, a voltage opposing the driving voltage must be inserted by the breaker to drive the current to zero.

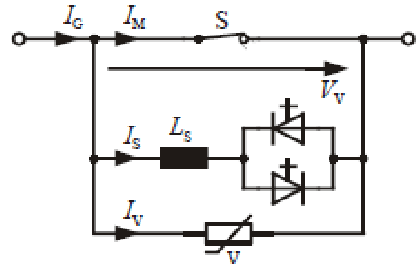
Because of difficulties to integrate the three functions of the DC breaker into one element, current breaker designs split the functions over different devices by making use of parallel paths [21]. Depending on switch technology, DC breakers can be categorized into solid state breakers (using power electronic switches), mechanical breakers and hybrid breakers, making use of a combination of both switch technologies. Conceptual implementation of these breakers is shown in Fig. 11. Typically, a surge arrester clamping the voltage to a value of 150% the nominal voltage is used [22]. This surge arrester also performs the energy absorbing function needed to dissipate the stored energy in the system inductance [23].



(a) Solid state breaker [22].



(b) Resonance breaker [24].



(c) Hybrid breaker [22].

Fig. 11: Circuit breaker concepts based on switch technology

Current proposals often include additional inductors to be placed immediately in series with the DC breaker in order to gain sufficient time to correctly detect the actual fault location and perform the breaker switching. These proposed inductors have a inductance value of up to 100 mH. As such the breaking unit consists of the breaker itself and the inductor placed next to it. This "passive" component influences the DC grid dynamics. The behavior of DC system interactions in a system consisting of fast control loops, including both DC inductances and the capacitive behavior of DC cables is not yet fully understood [25]. The complexity further increases when considering the interoperability of converters from different manufacturers.

IV. Modeling over different time frames

In an electric power system, different time constants ranging from microseconds up to minutes and even days determine the dynamic system response. This wide range introduces a number of challenges when it comes to modeling and controlling transmission systems. Including all time constants results in a very complex system to solve and is usually only feasible for a system relatively small in size. Therefore, different classes of power system programs have been developed. A distinction is traditionally made between electromagnetic transient (EMT)-type programs, electromechanical stability programs and steady-state power flow programs.

As indicated by its name, EMT-type programs have historically mainly been used to simulate electromagnetic transients in the system, i.e. changing currents and voltages that are a result of exchanges of the energy stored in the electric field in capacitances on one hand and the energy stored in the magnetic field of inductances on the other hand. Typical examples of phenomena for which this type of programs has historically been used are switching transients, lightning impact and transient overvoltages.

Electromechanical programs are designed to address the problems that can originate from the exchange of the kinetic energy stored in large rotating machines (primarily synchronous generators) and the power system. Typical phenomena studied with these types of programs are power oscillations and the associated transient stability of the system. A fundamental distinction between these two classes of programs, both intended to study dynamic interactions in the power system, is that in EMT-type programs the currents and voltages in the system are considered as state variables, whereas this is not the case for the electromechanical programs, where the periodically changing currents and voltages are typically modeled as quasi-stationary phasors. This simplification can be justified by the fact that the electromechanical energy exchange is largely dominated by relatively large time constants associated with the kinetic inertia of the generators. The time scales typically associated with these phenomena is several orders of magnitude higher than those associated with the energy exchanges between inductances and capacitances inside the AC system and hence, the faster dynamics if currents and voltages can typically be disregarded.

When the system dynamics are of no concern and one is only interested in the steady-state operation of the power system, the models can be reduced further by eliminating the temporal aspect from the analysis and by calculating the system using so-called power flow programs. The description of the system in this respect has been traditionally used for system contingency studies and for determining the optimal operation of the power system. A thorough discussion on the classification of different AC power system stability phenomena and the time scales involved is found in [26].

A. *Modeling Power Electronic Converters*

It is clear from the previous discussion that the AC system has historically provided a relatively clear means to distinguish between slow and fast interactions and that two different classes of power system software originated from the model reduction that originates from this distinction. On the one hand, there are the EMT-type programs describing the currents and voltages in the time domain, which causes a high relatively high computational burden. On the other hand, the electromechanical programs start from the description of the system currents and voltages by means of quasi-stationary phasors. Using this quasi-steady-state representation, the focus of these programs inherently is on slower system dynamics of which the associated frequencies are lower than the fundamental frequency of the power system.

For the sake of completeness, the concept of time-varying dynamic phasors, which is based on a Fourier approximation of the system quantities, should be mentioned here as a compromise to also include frequencies above the fundamental frequency whilst avoiding the high computational burden of a full time domain representation.

This rather distinct categorization for the power system phenomena based on whether their associated time constants are low or high as compared to the fundamental period of the voltages and currents in the AC system has been graphically depicted in Fig. 12.

The introduction of power electronic devices is challenging this approach to power system modeling. The switched nature of these devices and consequently, the much higher bandwidth associated with the control loops mean that the corresponding control actions can be very fast when compared to the time scales that traditionally have been associated with AC power system controller dynamics. This has been depicted graphically in the general classification of different dynamic phenomena and control dynamics in AC and DC systems in Fig. 12.

B. *Converter models for different time frames*

Before addressing the details of the challenges raised by the introduction of HVDC grids to the picture, it is worth to consider the different system models that were developed as a result of the introduction of power electronic devices in general and VSC HVDC specifically, in the power system.

1) Models for electromagnetic transient studies: The detailed nature of the EMT approach, combined with the specific characteristics of the power electronic systems, make EMT-type programs an interesting choice for developing the models for these systems. Although the switched nature of the power electronic components can be challenging with respect to the representation of these components in EMT routines, the introduction of power electronics in the power system has given rise to new classes of models and software routines to simulate these components in detail. Using the most-detailed models, the EMT approach thus allows to accurately represent the switching dynamics and electromagnetic transients, but this modeling detail comes at a high computational cost. The main

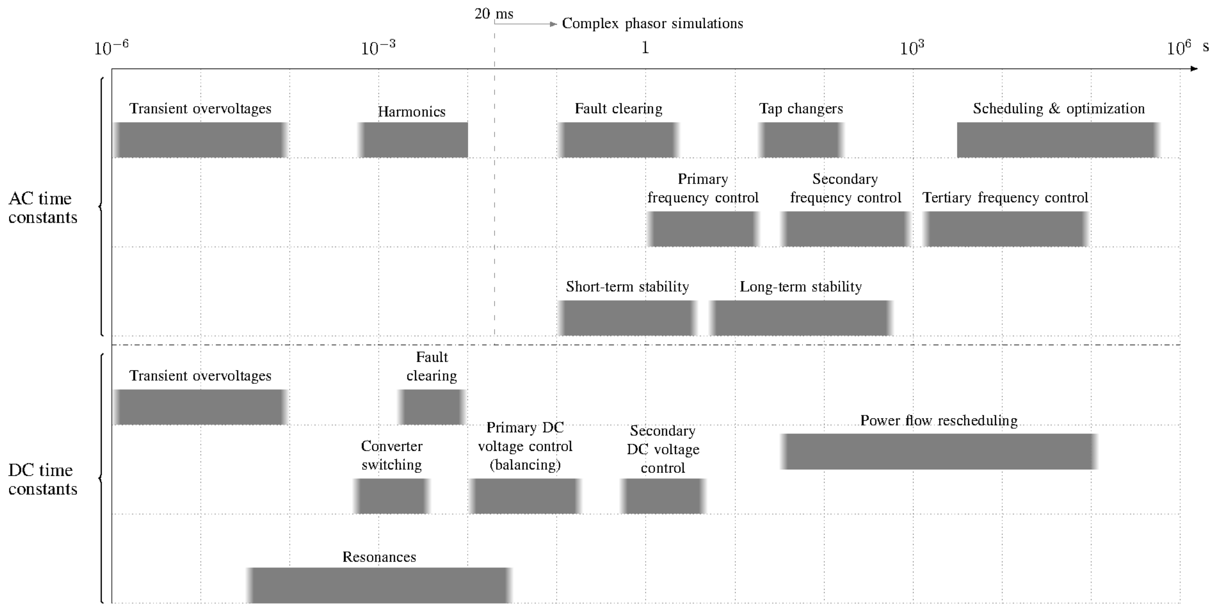


Fig. 12: Overview of AC and HVDC grid dynamics. [27]

merit is that the VSC HVDC system as such can be represented in great detail, allowing to fine-tune control parameters and to investigate, among others, a detailed representation of new converter topologies [28], [29], as well as higher-frequency interactions, possible resonances with the local power system, DC fault analysis [30] and protection strategies [31]. The high computational burden makes these switching models less suitable for studies of large power systems. Furthermore, the models require a detailed knowledge of the converter topology, often down to the component level, which makes them all but generic. Parameterizing and using such models can take more time even if sufficiently precise and accurate data is available. However, a major issue is that such models and data are often not available and contain proprietary information since they can only be supplied by manufacturers of the equipment.

Alternatively, the converter model can also be simplified to an averaged model for use in EMT. Such averaged models are often encountered in simulations of power electronics [32]. One of the main aims when developing these models is to reduce the order of the system by eliminating the actual switching behavior of the components by only taking into account the overall, averaged result of the switched control action. As an example, a simple two-level converter can be simplified from a converter representation including switches in each converter arm to a voltage source in each phase, which produces a waveform that is mainly dictated by the DC voltage and modulation index. It is clear that, under steady-state operation, the voltage in the three phases will be sinusoidal and at grid frequency.

2) Models for electromechanical transient studies: As discussed in the previous section, electromechanical stability programs allow to simulate more complex power systems by representing the AC power system by phasors. When the modeling of VSC HVDC systems is considered in this context, the description of the AC system in terms of fundamental frequency phasors justifies an approximation of the VSC that is similar to the way generators are modeled in the system. In other words, the observation made when discussing the technique of average modeling in power electronic software, namely that the converter will appear as a sinusoidal voltage source as regarded upon from the AC system, justifies the representation of the converter by an AC voltage source of which the amplitude and phase angle (or alternatively the d- and q-component) are controlled independently. Although switching models reveal more details, simplified and averaged models are well suited to study the VSC HVDC system control response [33]. Furthermore, these models are to a high degree independent of the actual converter topology.

3) Models for power flow studies: Contrary to the previous classes of programs, power flow algorithms only represent the steady-state operation of the system after all transients have died out. With respect to VSC HVDC systems, power flow models allow to study the overall effect of converter outages and e.g. the effect of a distributed voltage control on the AC and DC power flows.

C. Modeling other grid components for different time frames

An aspect that has been left out of the discussion so far, but is equally important, is the appropriate modeling of the other components, such as e.g. cables, overhead lines and breakers, in the HVDC grid.

As an example for different degrees of detail in HVDC grid models, we will rather take the DC cable as an example and shortly discuss the applicability of the models for the different classes of power flow studies. In general, a cable can be modeled in various ways:

1) Detailed frequency-dependent cable models.

2) (Cascaded) π-sections including lumped cable resistance, inductance and capacitance.
3) (Cascaded) π-sections including lumped cable resistance and capacitance, but neglecting cable inductance, thereby eliminating line currents as state variables.
4) Lumped resistive element.
5) Copper plate model, neglecting grid impedances

The modeling detail of the cable is important, since not using the appropriate model for a study, might either lead to an oversimplification or an unnecessarily detailed description of the problem under consideration.

In EMT-type programs, the most detailed models that are typically encountered are frequency-dependent cable models. These models normally start from a rational approximation of an analytic description of the cable geometry, yielding a similar frequency response [34]. This modeling approach yields a very accurate description of the cable frequency response, up to the MHz range. Such models are typically encountered in system protection studies.

A commonly used alternative for studying control interactions is to use a lumped parameter representation, possibly cascading several line segments to increase the bandwidth of the model when using longer cables. Although a commonly used representation for control interactions, one has to beware of the fact that cascading several sections can create so-called "ringing" at the intersections due to wave reflections at the junctions [35], which might could lead to false conclusions on e.g. the stability limits of the system.

The order of the model can be significantly reduced by also eliminating the cable inductances, since this removes the current as state variables from the equations. In this way, the HVDC grid thus simplifies to a network of capacitors interconnected by resistances, maintaining only the overall voltage dynamics of the system. Disregarding the capacitances as well also removes the voltages as state variables, which results in an all resistive network that can be used for steady-state power flow studies. Further simplifications include copper plate based models for market studies as well as dynamic studies, in which an aggregated lumped capacitor represents the DC system dynamics.

Although the applicability of this very simple representation is well-defined, the applicability of the other classes of models for the different classes of power system programs is not that well-defined yet. This specifically holds for models meant for inclusion in electromechanical transient software, since one of the fundamental assumptions of this class of programs is that the dynamics of interest can be described as phasors, thereby leaving out the AC voltages and AC currents as state variables. At the DC side however, the overall system response and the control interactions between different converters is determined mainly by the DC voltages and currents. One has to consider whether and to what extent the dynamics of the DC system need to be represented to obtain a valid overall system response, thereby taking into account the underlying simplifications of the steady-state phasor representation at the AC side.

D. Interaction of AC-side and DC-side dynamics

Despite the excellent controllability of VSC HVDC converters, which allows the integrated system to provide ancillary services, the power electronic interface poses limits to the operation of VSCs. This manifests itself particularly during system disturbances. Among other phenomena these include:

- VSC valve overcurrent protection;
- Converter overcurrent protection;
- Converter undervoltage limits;
- Converter overvoltage limits;
- DC faults;
- AC-side fault ride through;
- DC-side active power control;

1) Converter Protection: On a power electronic level, the overloaded valve is immediately blocked after overcurrent detection and currents flow through the anti-parallel diodes or bypass thyristors only [36]. This inherent converter protection may disturb the overall DC-side voltage and possibly unbalance the voltage distribution across the MMC capacitors, depending on the converter topological properties. Consequently, control mechanisms are triggered that balance the voltage distribution along the DC-side capacitors, for instance by shortly blocking the VSC output power and gradually restore it. Hence the time-frame of interest of this protection mechanism ranges from several µs to as long as 10 s.

Besides the valve protection, which triggers on instantaneous values, the current *set-points* are limited internally by the VSC control scheme. The vector control scheme sets the active (i.e. i_d) and reactive (i.e. i_q) parts of the current. If the amplitude of the current set-point exceeds the current rating of the VSC, i.e. $\sqrt{{i_d^*}^2 + {i_q^*}^2} > |i|_{max}$, the set-points must be curtailed, which can be done by limiting proportionally or by giving precedence to either the active or reactive part. d-axis priority maximizes the active power output of the converter in the event of disturbances whereas with q-axis priority, terminal voltage support is maximized. This discontinuous behavior has a time-frame of interest in between 1 ms up to several s and can be included into time-domain simulations with relatively idealized models.

The converters are also typically equipped with undervoltage and overvoltage protection to protect the converter against damage. It is important to make a distinction between the limit that the device can withstand physically, the one implemented in the controls and the one as defined by (future) grid codes.

2) DC-side active power control: The VSC HVDC active power control strategy has a significant influence on the interaction with the interconnected AC systems. Some active power control alternatives are related to variations in the direct voltage (e.g. voltage margin method, direct voltage droop), in which the interaction between the DC and the AC side is largely dominated by DC transients. Note, in some cases the possibility to contribute to the DC-side active power control is fully determined by the AC system it connects to, such as in the case of the connection of offshore wind farms (see section II-E). Contrary to DC faults, the time constants of interest of the active power controllers are comparatively high (i.e. $>5\,\mathrm{ms}$), which allows a simplified representation of the DC-side dynamics.

The previous discussion shows that during both disturbed and non-disturbed operating conditions, AC-side and DC-side oscillations will connect. Depending on the particular method, this connection is mutual, which may even cause propagation of power system dynamics from one synchronous area to the second [37]. The time-frame of interest spans from small-signal stability (e.g. control interactions, power oscillation damping) to even transient stability (e.g. angle oscillations after AC-side faults).

E. HVDC grid modeling challenges

As the previous discussion already hints, the introduction of HVDC grids is challenging the way the power system and the different components have been modeled in the past. When compared to the traditional division of AC system dynamics, the phenomena in DC systems are a couple of orders of magnitude faster and pose a number of modeling challenges:

- The absence of a substantial level of energy storage (see also section II), makes DC voltage deviations much faster than AC frequency deviations, where the AC system inertia determines the rate of change of frequency. This results in quasi-instantaneous converter set-point changes when considered from a traditional AC system stability perspective.
- The absence of reactive grid elements limiting the short circuit current requires HVDC grid protection coordination to be a couple of orders of magnitude faster than traditional AC system protection. When such components are introduced they cause additional dynamics in the system.
- The introduction of new generations of VSCs using modular multilevel converters (MMC) with a large number of individually controlled modules poses challenges with respect to converter modeling and representation in system studies.
- The complex nature of the VSC converters and their control impede the development of generalized, yet detailed converter models. Such models are needed when converters from different manufacturers, each with their own topology, control loops and time constants, are interconnected in one single DC system.

The HVDC grid time constants are thus in general several orders of magnitude smaller than those in AC systems. Furthermore, the clear distinction between fast and slower system dynamics based on the AC system frequency no longer applies to HVDC grids and might need to be revised for hybrid AC/DC systems.

F. Active Power Control

A challenge arises from the introduction of voltage droop control since it invokes a system-wide response as the result of a DC system contingency. The introduction of HVDC grids therefore also challenges the secure operation of AC power systems. Especially combined with the introduction of a massive amount of renewable energy sources, this urges for new assessments of system reliability that go beyond the existing N-1 criterion, which has to be replaced by more advanced statistical methods (see Section VII).

G. Modular multilevel converter modeling

Due to the introduction of the MMC concept, a number of challenges arose with respect to converter modeling. Whereas two-level topologies are still straightforwardly simplified for EMT simulations by grouping all IGBTs in a converter arm in one equivalent switch, the high number of stacked modules makes full-detailed time domain simulations time consuming. Recent approaches include a time-varying Thévenin equivalent approach [28], a continuous-variable dynamic model, considering the sum of the capacitor voltages instead of the individual capacitor voltages [38] and a continuous model including blocking and deblocking behavior of the converter [12]. An overview of different models available for EMT studies is given in [11].

V. Dynamic simulation of mixed AC/VSC HVDC systems

System-wide scale issues (e.g. transient stability, inter-area oscillations) are key in the grid integration analysis for VSC HVDC transmission. As discussed in section IV, this is traditionally studied in the time-domain by stability-type programs, which are designed to correctly represent electromechanical oscillations in AC systems [39]. The nature of these oscillations is well defined by machine physics and have a bandwidth in between $0.1\,\mathrm{Hz}$ and $10\,\mathrm{Hz}$. This gives rise to reduced-order modeling of connected devices and quasi-stationary modeling of the AC transmission network by complex phasors (see section IV). The system model of electromechanical simulations covers a set of differential-algebraic equations:

$$\dot{\boldsymbol{x}} = \boldsymbol{f}(\boldsymbol{x},\boldsymbol{y}) \tag{7}$$

$$\boldsymbol{0} = \boldsymbol{g}(\boldsymbol{x},\boldsymbol{y}) \tag{8}$$

where $\boldsymbol{x}$ and $\boldsymbol{y}$ are the set of state variables and algebraic variables respectively. The network equations and model current (or power) injections are included in (8), whereas device and machine differential equations are contained in (7). This approach allows simulating large systems with time step-sizes for numerical integration in the order of half a cycle.

The non-linear and sometimes discontinuous behavior of high-capacity VSC HVDC schemes discussed in section IV-D may impair transient stability, which requires the causing physical phenomena to be modeled correctly. As discussed previously, the time-constants of these transients are small, which implies that their inclusion into (7) results in a stiff system with time constants in the order of the electromagnetic transients inside the AC system which are of no interest when studying AC system-wide interactions. The corresponding VSC and DC-side modeling does hence not fit into the aforementioned simulation paradigm. Generally speaking, electromechanical simulations cannot systematically handle mixed AC/DC networks. Currently, a common approach to include arbitrary VSC HVDC structures is to decrease the time step-size [40]. This cancels out the computational merit of (8) in case a fixed time step-size is adopted. The application of a variable time step-size is an option [41], though this is a non-trivial feature of the most commonly used commercial software, and often at the cost of an enfeebled numerical stability [42].

On the other hand, the current state of the art in computational power allows modeling of large networks in high detail by (quasi) real-time EMT-type and stability-type simulations [28], [43], [44]. EMT-type simulation requires sophisticated line, cable, and equipment data that is necessary to produce a realistic EMT representation of the power system. These are often not available, neither are real-time simulation facilities. Hence will grid studies often be restricted to offline EMT or electromechanical simulation on stand-alone computers. This is specifically the case when an accurate model of the power electronic converters is not available: only as proprietary model from the manufacturer or as generic models with uncertain parameters.

Simplification or aggregation of the AC system can be done in order to make the size of the AC network model compatible with the computational boundary conditions of an offline EMT-type simulation [45], [46]. This procedure is non-trivial and stretches beyond a mere connection of existing dynamic models.

The aforementioned modeling and simulation options do work, but are in light of computational requirements non-ideal. Due to the extensive range of the eigenvalues to be addressed, the dynamic simulation of mixed AC/VSC HVDC systems requires the benefits of both electromechanical and EMT-type simulations: fast and accurate computation.

Co-simulation is a widely applied method to couple the response from a particular subsystem with the dynamics of another subsystem, while both subsystems are mostly modeled and simulated using different methods. The approach is shown in Fig. 13, where simulation 1 and 2 are two separate programs that are executed sequentially, and exchange data about the respective subsystem response governed by a predefined sequence, the *interaction protocol*. For the specific case of electro-mechanical stability programs combined with EMT-type simulations, both simulations use different time step-sizes (i.e. $\Delta t >> \Delta t_{\text{emt}}$), and hence data about angular swings, voltages, and current injections are exchanged at the start and end of each calculation step of the electro-mechanical simulation.

A more advanced co-simulation approach is to execute the electro-mechanical and EMT-type simulations in parallel. This is shown in Fig. 14, which enables the execution of each program on a separate CPU and thereby potentially providing a computational benefit. This approach has been adopted between PSS®E and PSCAD in [47], providing a execution speed benefit of around 40 % compared to the EMT reference simulation.

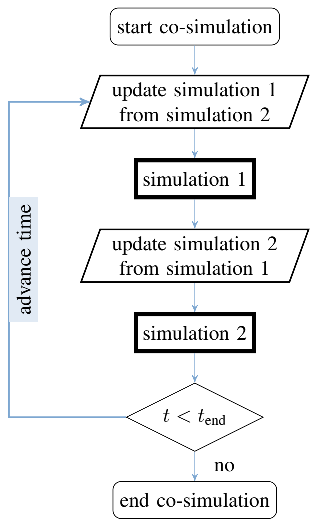


Fig. 13: Sequential co-simulation workflow.

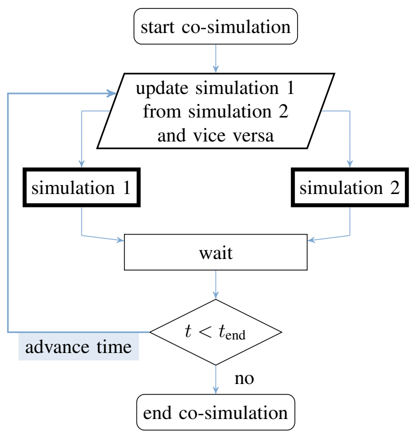


Fig. 14: Parallel co-simulation workflow.

In case no separate EMT-type program is available, the detailed subsystem should be represented by dedicated state-space modeling. This is for instance done in PSS®E, where dedicated point-to-point link models of both HVDC Light® [48] and HVDC Plus® can be applied. For generalized multi-terminal VSC HVDC schemes the common time step-size of around half a cycle cannot be maintained due to the inclusion of the DC-side transients [49]. A solution to this issue is the application of multi-rate techniques, in which the dynamic model of interest contains an inner integration loop that simulates the VSC HVDC system at a much smaller time step-size, Δt_2 [50]. This approach is shown in Fig. 15. Inside the inner integration loop the subsystem should at t_n 1) take dynamic nodal and device data from $\boldsymbol{x}$ and $\boldsymbol{y}$, 2) update and execute the inner state-space model until $t_n + \Delta t$, and 3) update $\dot{\boldsymbol{x}}$ in such a way that is is compatible with the main integration loop. This sequence is repeated each time step t_n, and can for mixed AC/VSC HVDC systems lead to a significant performance improvement depending on the AC subsystem size.

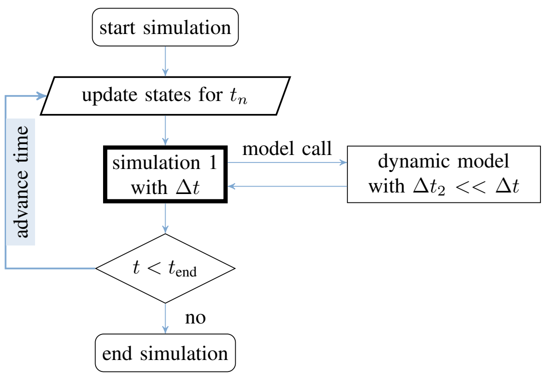


Fig. 15: Multi-rate implementation of dynamic models.

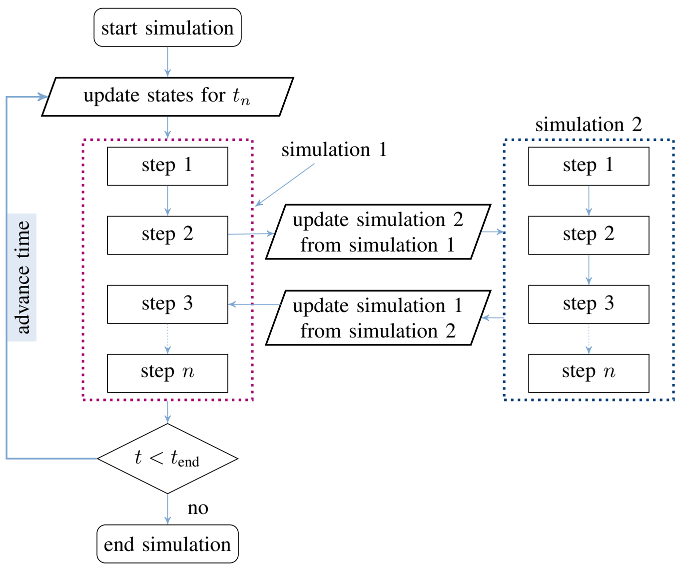


Fig. 16: Hybrid simulation.

Another alternative to co-simulations is the application of a hybrid simulation, the approach of which is depicted in Fig. 16. The electro-mechanical program executes several steps each time step, such as fault handling, solving the algebraic equations (8), and the numerical integration of (7). The EMT-type simulation is embedded into the electro-mechanical program or vice versa. In this case, the interaction protocol can be more flexible compared to co-simulations, where the applicability depends on the application program interface (API) of the respective programs.

Being first developed in [51] by sequentially executing a electro-mechanical program and an EMT-type simulation during faults, hybrid simulations were mainly used to study the integration of line-commutated converter (LCC) HVDC. This simulation concept has been applied [52]–[54], improved [55]–[57], and generalized [58] over the the past decades.

One of the key issues with co-simulation, multi-rate models, and hybrid simulations is the interaction of the two types of software and how both are interfaced [59]. Challenges to this approach relate to the representation of the nearby AC grid surrounding the converter (i.e. the extent to which the AC grid can be simplified so that the models are still accurate enough to represent the dynamic AC/DC interactions of interest [60]), and the general applicability of the respective interfacing techniques including the availability of all necessary variables via that interface. The prospects of building more complex HVDC systems, combined with the different nature of system interactions of HVDC compared to AC grids, make that methods for co-simulation and model development will be important research topics in the years to follow.

VI. Connection of Offshore Wind Resources

The first application which is considered in greater detail is the modeling of HVDC systems for the connection of offshore wind resources. One of the main triggers for the development of HVDC grids is the need for transmission systems to connect the increasingly distant offshore wind power plants (WPP). When connected using HVDC transmission systems, offshore wind power plants are not synchronous with the main onshore grid and therefore the operation and control requirements differ from those of AC connected WPP. The offshore grid must be established and maintained by means of the VSC HVDC rectifier in close coordination with the wind turbines. Furthermore, the WPP are expected to provide support both to the HVDC transmission system and the onshore grid(s) according to the relevant grid codes [61]–[64].

The control of offshore wind power plants requires the coordination and integration of WPP and VSC HVDC converters. The coordination of controllers and protections is a fundamental issue for VSC HVDC connected offshore wind power plants. An appropriate integration will often deal with different manufacturer technologies, and therefore it is extremely important to clearly specify how this integration can be conducted in a given installation.

An example offshore wind power plant layout [65] is sketched in Fig. 17. The analyzed system considers a VSC HVDC converter which is installed in a platform and connected by means of export cables to transformers located in two platforms where they collect the power from several strings of wind turbines. Each transformer collects the corresponding nominal power in normal operation, however the transformers will be typically overrated to allow to operate the WPP at partial load in certain circumstances with only one transformer. Reactive power compensation equipment may be considered depending on the configuration. Reactive power can be provided by the VSC HVDC converter, the wind turbines or both.

A. Requirements

The control and protection integration of the WPP and the VSC HVDC will be required to provide the following functions:

- The **offshore grid frequency** must be controlled at the desired value. This task is performed by the VSC HVDC converter which imposes the offshore grid frequency.

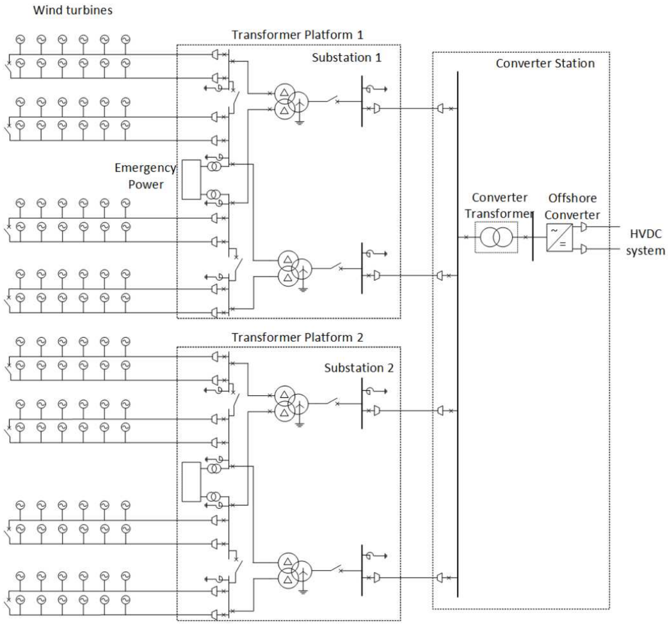


Fig. 17: Example offshore wind power plant connected to a VSC HVDC unit

- **Active power management**: Active power will be managed in order to extract the maximum possible power for low wind conditions, extract the nominal power in high wind conditions and reduce power when needed or required by the grid operator.
- **Reactive power management:** The management of reactive power is strongly linked to the voltage control both by the wind turbines and the VSC HVDC. The WPP dispatches reactive power references to the wind turbines. The offshore grid voltage must be maintained in appropriate levels in all the wind turbines and in the VSC HVDC converter.
- An appropriate **start or stop sequence** must be applied considering issues such as the transformers inrush current and the possible voltage transients. Auxiliary power and communication system may be needed for the start-up and shut/down sequences.
- **Fault ride-through capability** for onshore, offshore and HVDC grid faults.
- **Main grid support:** VSC HVDC connections are expected to provide support to the grid where they are connected:
  - Voltage support will depend mainly on the grid side VSC HVDC inverter.
  - Frequency response (including primary frequency support and inertia emulation) requires coordinating the VSC HVDC inverters, VSC HVDC rectifiers and the WPP. The WPP VSC HVDC rectifier will be demanded to reduce or increase power for onshore grid frequency support. In this case, one possibility is to change via communications the active power command or to mimic the onshore frequency on the offshore grid in order to obtain the same response from the WPP as it would perform in an onshore system. In any case, communications are needed.
  - Power system stabilizer capability
- **Operation under communication failure**.
- Provide **auxiliary power** to the WPP (1-2%) when there is no wind.

B. Modeling and control of offshore wind power plants

The available controllable variables are the active and reactive power of all the individual wind turbines and also the active and reactive power (or the equivalent frequency and voltage) of the VSC HVDC. The control scheme will have to ensure both the active and reactive power balance, injecting all the wind power generated to the HVDC cable, while maintaining an appropriate voltage in the different buses and controlling the WPP frequency.

The wind turbine active power reference establishes the maximum power that the wind turbine will generate, allowing to reduce it and loose part of the wind available power when needed. If the maximum reference power is not overcome, the wind turbine will operate with maximum power point tracking (MPPT). The wind turbine is usually equipped with a DC chopper in the DC bus which can allow fault ride through capability. The chopper will be appropiately coordinated with slower power reduction devices such as the wind turbine pitch mechanism.

Offshore VSC HVDC connected WPPs are equipped with a wind power plant controller, as shown in Fig. 18, which allows regulation of active and reactive power at the (offshore) WPP connection point. The controller receives active and reactive power measurements at the WPP connection point and sends active and reactive power set-points to the local controllers of the individual wind turbine generators. In the case that the local wind turbine generator controllers are using voltage instead of reactive power set-points, voltage set-points will be issued. The coordination between the different systems will depend significantly on the delays between the commands sent and responses obtained. These delays depend on the communication delays, the controllers execution times and the time response of the commanded devices (for example the wind turbines). The considered communications systems can include (see Fig. 18):

- COM1: Communications between the WPP control system and the individual wind turbines, to allow power dispatching.
- COM2: Communications between the grid operator and the WPP control system, to allow power reductions for congestion management.
- COM3: Communications between the onshore VSC HVDC converter and the offshore VSC HVDC converter to allow active power regulation for frequency support.
- COM4: Communications between the grid operator and the onshore VSC HVDC converter.

The overall modeling structure of the system can be summarized as:

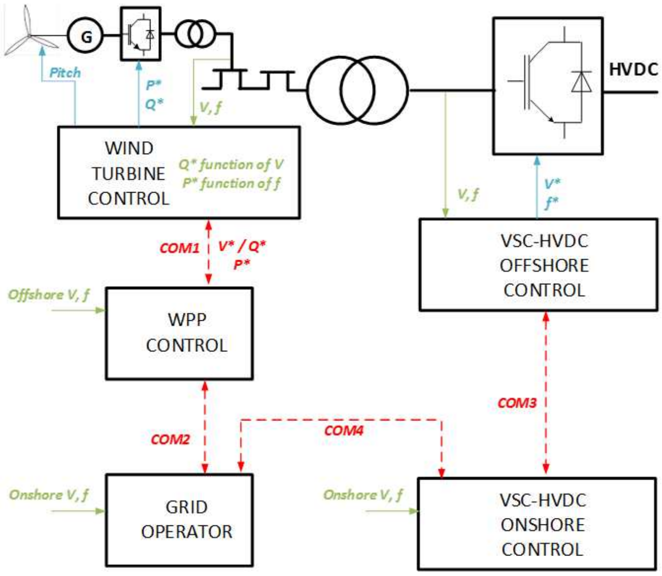


Fig. 18: Control integration

- Offshore VSC HVDC converter: controls voltage magnitude and defines the offshore AC system frequency at the AC terminals. As the converter is a grid forming unit, it will impose the system angle and frequency at every instant. Therefore, the VSC HVDC converter will not require any phase locked loop (PLL) to synchronize with any grid. The voltage will be regulated with a voltage controller cascaded with a current controller (where the voltage controller sets the references for the faster current controller). In some applications, it will be required to change the offshore frequency (for example to demand frequency response from the wind turbines, an option is to mimic the onshore frequency in the offshore grid). This will be achieved by imposing the required angle (calculated with the desired frequency). The modeling and control of VSC HVDC converters for offshore grids may become more challenging when considering multiple infeed offshore stations where multiple converters are to be coordinated.
- WPP: delivers active power and regulate reactive power at the wind turbine connection points for minimizing losses or controlling voltage. The wind turbine controllers will synchronize with the offshore grid by means of a PLL, and will inject the required amount of active and reactive power.

The design of the protection scheme for the offshore WPP will take into account the low short-circuit current of the offshore grid, related to the largely power electronics based nature of such a grid. Protections will be designed and adjusted to avoid any damage to the equipment.

C. Fault-ride through

A vital subject of the operation of VSC HVDC is the capability to “ride through” a fault at the AC side of a VSC converter. This is a particular challenge for offshore WPPs: for AC faults the VSC HVDC link acts as an electrical barrier between the onshore and offshore AC network, so the offshore WPP does not perceive the onshore fault and the corresponding limited active power delivery to the onshore grid. As a result, the direct voltage rises to unacceptably high values shortly after the fault, which has to be resolved within this same short period (in the order of several ms) to ensure fault-ride through. This can be dealt with by including an HVDC dynamic breaking resistor (controlled resistor, commonly referred to as a DC chopper) in the DC circuit to dissipate the excess energy stored in the DC-link capacitance, or by curtailing mechanisms in the WPP [66], [67]. After fault clearance, it is likely that the wind turbines have obtained a different operating point, which changes the available active power after the fault, and hence influences post-fault oscillations. Simulating fault-ride through of VSC HVDC schemes requires a detailed representation of electromagnetic phenomena in the DC system as the protective equipment triggers on the direct voltage oscillations, The overall time-frame of interest of the FRT scheme ranges from around 100 µs to 10 s, depending on the active power recovery scheme.

VII. Multi-zonal hybrid AC/DC grid operations

The second application discussed in greater detail is the operational time frame of the hybrid AC/DC grid.

Future power systems with increased HVDC connections will require further integration of these new devices in their system operations. This is the case for HVDC grid(s), but also for systems with many HVDC (point-to-point) links. This integrated system is expected to be operated in a similar manner as the current multi-zonal AC system. This means that an HVDC grid will be integrated in the current system operator business, and this within the different operational time frames of the system operator. This requires that the HVDC grid(s) are subject to a given grid code, operate within the market framework and can contribute to delivering ancillary services.

Current HVDC lines are also connected to the existing power system, however, they are often not fully integrated in all aspects of the overarching system management. Up to now, they also form a relative small share of the total transmission infrastructure. As their share increases, they will form a more important part of the overall transmission system, especially as they typically have a high power rating, are long distance and their controllability influences system operations in a wide range. This influence requires them to be incorporated in the operational procedures of the AC system.

One important difference in operation between an HVDC link and an HVDC grid is important to note: the former is very often operated at full capacity, making maximum use of the (expensive) equipment while the lines and converters in a (meshed) HVDC grid are generally not operated at rated capacity. In general it is in meshed grids not even possible to load all lines up to rated capacity at the same instance, even when the injections are controllable. Rather, these converter stations can be compared to (controllable) transformers in AC systems, interlinking different layers.

This section gives an overview of some aspects of power system operations that can require additional attention when considering hybrid AC/DC systems. It highlights the possible influence or changes that can be expected with HVDC grids. Special attention is paid to the interface between stakeholders and systems. The choices that need to be made in the future to guarantee a successful and efficient system operation in the presence of both AC and DC systems are indicated.

A. Who is operating the HVDC link or grid?

The manner in which HVDC converters are controlled and controller settings are determined depends mainly on who operates the DC system, and the requirements under which the link is operated, the DC grid code.

In some cases it is important to make a distinction between the entity that performs the operations and the entity that dictates the operations. An example is a link where the transmitted power is set through auctioning on a market, while the actual control room operators are "only" responsible for assuring that the system is operated as such. For the remainder of this section, the decision maker is meant when we refer to the operator.

A hybrid AC/DC grid can have the following operator options:

- **Single operator:** In the single operator configuration, the entire AC and DC system are operated by a single entity, which can optimize the entire system;
- **Regulated DC system operator:** The DC system is operated by an independent operator, which operates the DC system under a regulated regime;
- **Merchant/private DC operator:** The DC system is operated by a merchant operator, which operates the DC system independently;
- **Territorial operator:** The system operation and ownership is linked to the location (e.g. a country).

Two additional notes must be made to the aforementioned options:

- The control of the power electronic converter, which is at the interface of AC and DC, can in theory belong to either the AC or the HVDC grid operator. In theory, it can even be split (for instance with the active power control governed by the HVDC grid operator, and the reactive power or AC voltage controlled by the AC operator);
- The control of the power exchanges between AC and DC systems can have an effect on a neighboring system, even if there are no direct injections in that system.

An illustrative example of how the ownership can influence the operation of the combined AC and DC system is given using Fig. 19. Considering an AC and a DC system that are connected with 5 converter stations. In the north of the DC system, a large netto power injection is present, which needs to be transferred to the south of the AC zone where there is a large load. As all the links between the AC and DC system are fully controllable, the transfer is to a large extent controllable as well. A first option is to use the HVDC grid to transmit the power from the north to the south, and inject this power as near as possible to the load center. A second option is to directly transfer the electric power towards the AC system by using the northern interconnections. In a third option, the power transfer is distributed over the different links.

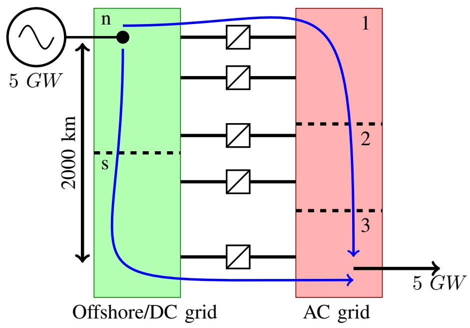


Fig. 19: DC and AC system flow

Consider now the case were the objective is to minimize the losses in the system. In the case of the DC operator, the second option is the most beneficial, while in the case of the AC grid operator, it is more beneficial to use option one, and transfer the power over the HVDC grid. In a system wide approach, an optimization over both systems is needed.

The matter is even more complicated when we consider that both the AC system and the DC system could be split into multiple system operators. In this case, the operation involves coordination over multiple borders. For instance, the flow through AC zone "2" is strongly influenced by the control of the different converters.

In real power systems, the operator of the power system has to ensure that there is sufficient:

- capacity on each converter;
- AC transmission capacity;
- DC transmission capacity;
- reserves in case of an outage in the AC system, the DC system or a converter station.

B. Unbalances in HVDC grids

Unbalances in HVDC grids can originate in a similar manner as in AC systems: either through a fault disconnecting a converter station that either imports or exports electrical power or through an unforeseen power injection, e.g. from a largely uncontrollable power injection such as an offshore wind farm. During the unbalance, the netto energy flowing in or out the system is not zero, which means that energy is accumulated or reduced in the HVDC grid by charging or discharging of the DC capacitors. As a result, the DC voltage will increase or decrease (see also section II-E).

When an energy unbalance occurs (e.g. when a converter station is disconnected), the control of the DC voltage by the different converters will adjust the power injections immediately, distributing the deficit according to the droop settings. The overall voltage level in the HVDC grid is slightly lower or higher than the reference value due to this control action. This behavior is similar to the primary frequency control. After this first action, two further actions are needed. The DC voltage needs to be restored and the change in power exchanges with the different neighboring systems need to return to the original values. As such, there is a need to adjust the power injection set-points to meet the scheduled exchanges, especially so if multiple zones or synchronous zones are connected to the DC grid. This requirement is very much in line with the secondary and tertiary control which is used in the AC system.

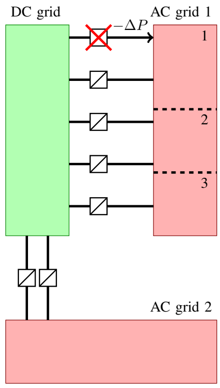
Fig. 20 illustrates how the unbalances in a HVDC grid connected to multiple zones and multiple AC systems can be addressed in a system that utilizes droop control. Consider a case where a DC converter station outage causes an unbalance $-\Delta P$ in the DC system and at the same time also in the corresponding AC grid 1 (Fig. 20a). As a result, the voltages in the system will drop throughout the HVDC grid, and the droop causes the healthy converters to change their power. Each converter will contribute for $\Delta P/6$, assuming equal droop settings, sufficient reserve power available on the different converters and disregarding the influence of the voltage profile on the power distribution [68] (Fig. 20b). At this moment the DC system is balanced, yet there is an unbalance in both AC systems. This unbalance is corrected in the third phase (Fig. 20c), where contribution from AC grid 2 is canceled and taken over by AC grid 1. In a final phase, the correction is made per zone, and the entire ΔP is handled by the converter(s) connected to the same AC zone 1 to which the outaged converter is connected (Fig. 20d).

Every power imbalance in the HVDC grid is directly shifted to the connected AC grids and not necessarily in an expected or desired way [70]. With the expansion of the HVDC grid this could become a problem, because if the imbalances reach a level that it influences the AC frequency beyond the control deadband for primary reserve (in Central Europe $\pm 20mHz$ [71], North America $\pm 36mHz$ [72]) it decreases the primary reserves of the AC grids in normal operation. In order to manage the HVDC grid power injections in the different nodes, a supervisory controller is needed which operates the entire system [15].

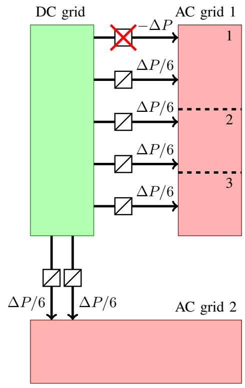
C. *Reliability of the hybrid AC/DC grid*

When considering the hybrid AC/DC grid, both contingencies at the AC and the DC side need to be taken into account. These contingencies influence the other system: line openings at the DC side might require redispatch which causes overloads in the AC system, or a short circuit at the AC system might cause a converter station to disconnect.

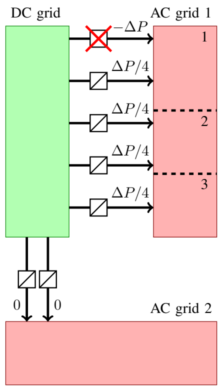
The hybrid AC/DC grid consists of a number of AC and DC systems operating in parallel. When considering the hybrid AC/DC grid reliability, it is important to consider on which part of the system the reliability criterion is calculated. To use the example of the N-1 criterion, one needs to decide whether the AC and the DC system(s) need to be “N-1” secure individually, or that the combined system(s) is seen as a single meshed system. In the first case, a multi-terminal



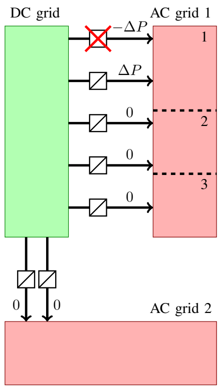
(a) Outage of a converter station connecting the HVDC grid with AC grid 1, zone 1



(b) Equal droop reaction causes all converters connected to the HVDC grid to contribute



(c) The schedule with AC grid 2 is corrected, resulting in only a contribution from AC grid 1



(d) Control zone 1 of AC grid 1 takes the full unbalance over from the other systems

Fig. 20: Addressing an unbalance in the DC grid through adjustment of the power injections [69]

HVDC system without meshes can never attain “N-1” secure operation as there is no inherent redundancy in that system. However, the same system might be “N-1” secure when the AC system to which it is connected is considered in the reliability calculation.

When a line contingency occurs at either the AC or the DC side, a redispatch of the converter injections might alleviate the overload. The controllability of the DC converters can be used to make optimal use of the installed assets. How this is done depends largely on expected level of reliability, the number of parallel paths (both in AC, DC and the combined system) and the involved stakeholders. It is important to note that the system reliability management occurs in different steps, from the operational planning phase up to operations [73], [74]. These steps involve different decisions in which the operation of HVDC converters needs to be taken into account. They can be used to enlarge system capacity on the capacity market, reduce congestion and perform preventive or curative actions [74]. They can additionally also contribute to the exchange of ancillary services.

VIII. Integrating HVDC systems in OPF

A. AC/DC OPF

Calculating the power flow and the optimal power flow are essential tools for the system planner and operator. As such, it is important that existing AC grid operation calculation tools are upgraded to also take DC converters, connections and complete grids into consideration. The basic methodology is an extension of the existing AC tools and adding additional equations and state variables for the DC system. Adding DC systems results in power flow equations at the DC side, controllable active and reactive power injections and the power balance over the converters including losses and droop actions [3], [75]–[81].

The classic optimization case can be written as a minimization of the objective function f to state variable $\mathbf{x}$, with equality constraints $g(\mathbf{x})$ and inequality constraints $h(\mathbf{x})$. This problem is extended into an optimization of function f_n to variables $\mathbf{x_n} = [\mathbf{x}, \mathbf{z}]^T$. Also the equality and inequality constraints $g(\mathbf{x_n})$ and $h(\mathbf{x_n})$. The subscript o is used for the original constraint functions and n for the added ones. The extended optimization case is

$$\min_{x,z} f_n(x, z) \tag{9a}$$

$$g(x_n) = \begin{bmatrix} g_o(x) \\ g_n(x, z) \end{bmatrix} = 0 \tag{9b}$$

$$h(x_n) = \begin{bmatrix} h_o(x) \\ h_n(x, z) \end{bmatrix} \leq 0 \tag{9c}$$

$$x_{min} \leq x \leq x_{max} \tag{9d}$$

$$z_{min} \leq z \leq z_{max} \tag{9e}$$

For the AC system, the non-linear equality constraints $g_o(x)$ express the active and reactive power equalities (following Kirchhoff's current law) for each node, thereby imposing the desired grid topology. The node voltage and generator powers are limited by directly stating stating upper and lower bound for the state variables. The non-linear inequality constraints $h_o(x)$ impose the branch powers to be limited by their maximum rating. The choice of these equation systems and state variables completely define the AC system.

To define the hybrid AC/DC grid, the additional state variables z, and constraint equation vectors $g_n(x, z)$ and $h_n(x, z)$ are to be set up in an appropriate way. The vector $g_n(x, z)$ consists of two different sets of equations itself: a set for the integration of AC/DC converters and a set for the DC grid.

To define the DC system with the methodology described here, the following additional state variables can be chosen:

$$z = \begin{bmatrix} P_{conv} \\ U_{DC} \end{bmatrix} \tag{10}$$

where P_{conv} stands for the DC side power injected into the connected AC/DC converters and U_{DC} the vector of DC node voltages. The converters can be modeled by an equivalent AC generator and a DC voltage source (figure 21). They are linked together using the loss expression [76]:

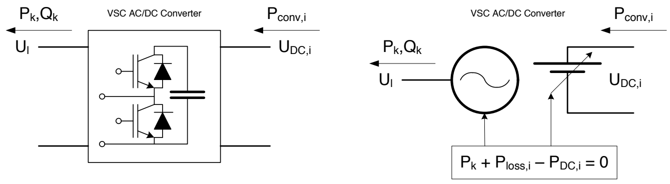


Fig. 21: Converter model equivalents. Left: AC/DC VSC converter, Right: OPF equivalent

$$g_i(x) = P_k + P_{loss,i}(U_{m,l}, P_k, Q_k) - P_{DC,i} = 0 \tag{11}$$

with $i = 1 \dots n_v$, the number of active converters. As can be seen in (11), this equation links the active AC and DC power together, by holding back the loss term $P_{loss,i}(U_{m,l}, P_k, Q_k) = P_{DC,i} - P_k$. Whichever the power flow direction, this term always remains positive. Most optimization solvers however require the calculation of the first and second derivatives matrices (Jacobian and Hessian) to exist in the feasibility region of the problem. Typically, the losses are expressed as a second order polynomial with respect to the AC converter current.

The HVDC grid equations are similar to the AC equivalents: they express the (active) power balance per DC node taking into account power transfer with the VSC converters and transmission to other nodes:

$$g_{br,i}(x_n) = U_{DC,i}^2 Y_{br,ii} + U_{DC,i} \sum_{j \neq i} Y_{br,ij} U_{DC,j} + \sum_k P_{conv,k} \tag{12}$$

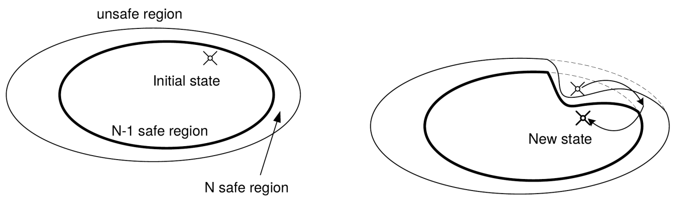
with $j = 1 \dots n_N$ the number of DC nodes, $k \in \{$set of converters connected to bus $i\}$ and Y the DC admittance matrix.

Fixed injections and extractions of DC power, e.g. to model the fixed infeed from wind power plants, are added to these non-linear equality constraints by the inclusion of a constant power value.

Upper and lower bounds on the additional state variables limit the DC power of the AC/DC converters and keep the DC node voltages within their operational range. Additional non-linear inequality constraints are needed to limit the DC branch powers.

Solving the optimization case can be done using standard optimization solvers. Depending on how the additional equations are formulated, the formulation might require a specific solver that is able to deal with non-linear and non-convex problems. In [82], the barrier method is used, while [83] uses the second order cone method.

Similarly to the AC OPF formulation, a number of simplifications can be introduced to reduce the computational burden. The most common simplification is the linearization of the equations, leading to an inaptly named DC-OPF formulation. It is important to note that, as with DC-OPF for AC systems, the accuracy is significantly reduced and the controllability



(a) situation before incident

(b) safe region evolution and grid state changes

Fig. 22: Schematic overview of the curative recovery actions after incident.

of the converters might push the system into regions which are far from the linearized set of equations. Depending on the application this reduction in accuracy can be acceptable or not.

B. Security constrained OPF

Based on the extended OPF case, also security constraints can be integrated so that not only the base case is optimized but also a number of possible contingencies are taken into account [82], [84]–[92]. A security constrained OPF allows the operator to integrate sufficient margin to safely operate the system, either by taking curative or preventive measures.

With the *curative approach*, the operator takes into account that, within a predefined time interval, he can restore the grid to a safe state, even when some of the grid elements are initially overloaded immediately after the incident happened (Fig. 22). The action sequence for which the operator is able to pilot the grid back to a healthy state, depends on the given control possibilities and time constants of the power flow control devices (e.g. HVDC converters, phase shifting transformers, power reserves). When the operator is given sufficiently fast control capabilities, then all the considered contingency states can be reached in time, provided that a feasible solution (without overloading components or exceeding voltage limits) is found for that security constraint. The curative approach is in this case nothing more than solving each contingency apart considering that the operator can deal appropriately with a particular contingency state when an (optimal) solution for that state has been found.

For the *preventive approach*, the grid operator ensures that for a certain range of contingencies (e.g. based on the "N-1" criterion), no grid element is overloaded after one of these grid events has happened. For the mathematical formulation of this approach, each individual contingency state needs to be included into the same case structure. The base topology is linked through a set of simple linear equality constraints, by equaling the generator and converter bus voltages and active power injections over the different cases: as such, the guarantee is obtained that indeed, the grid operator does not need to intervene immediately after the incident.

The solution of the preventive security constrained optimal power flow (SCOPF) is sub-optimal: the higher degree of network security comes at the expense of higher values of the objective function. Its mathematical expression is an extension of (9):

$$\min_{x_0} f_0(x_0) \tag{13a}$$
$$g_0(x_0) = 0 \tag{13b}$$
$$g_k(x_k) = 0 \tag{13c}$$
$$h_0(x_0) \leq 0 \tag{13d}$$
$$h_e(x_k) \leq 0 \tag{13e}$$
$$x_{min} \leq x \leq x_{max} \tag{13f}$$
$$x_k = x_0 \tag{13g}$$

with $k = 1 \dots c$ and c being the number of contingency cases. The subscript 0 is used to indicate the base case scenario and e for the emergency state limits of the grid elements.

The individual security constraints are linked together by (13g) stating that the operator should not alter set-points when the incident has happened. The state variables that are taken into account in this set of equalities are the active power and node voltage amplitudes of those buses containing generators or converters. An exception here are active powers on the AC and DC reference buses: including them would impose equal grid losses of the base and all contingency cases as well. This leads to unsolvable optimization cases and is in practical situations not required: the power imbalance is compensated by the reference generators and converters.

The state variables and function vectors are rewritten to adopt the notation convention of the beginning of this section: $x_n = [x, z]^T = [x_0, x_1, \dots, x_c]$, $g(x_n) = [g_0(x_0), g_1(x_1), \dots, g_c(x_c)]^T$ and $h(x_n) = [h_0(x_0), h_e(x_1), \dots, h_e(x_c)]^T$. The subscript 0 stands for the base case, all others $(1 \dots c)$ denote the individual c preventive security constrained optimization cases. The function vectors $g_k(x_k)$ with $k = 1 \dots c$, describe the grid situation of the contingency k and differ from the base function vector $g_0(x)$ by having put the grid element of the corresponding contingency scenario out-of-service or non-existent. This slightly modifies the grid topology locally.

As with the normal OPF, also the security constrained OPF can be simplified, for instance through the use of linear assumptions [92], [93].

C. Extending the OPF for practical systems

The aforementioned OPF and SC-OPF formulation needs to be implemented to fit the correct business case: the correct time frame with the matching objective and constraints. With the power system this also means taking into account the multi-TSO system and the market operations. Also the aspect of incorporating stochastic infeeds into an optimization framework is a further development. In [94], this is done using a linear representation of the power system.

IX. Conclusions

This survey paper presents the ongoing research towards modeling hybrid AC/DC systems and its challenges. The introduction of "new" HVDC systems and even grids will lead to a completely different behavior of the power system. They introduce deviating system behavior through their faster response times and at the same time provide additional controllability. The expected advent of HVDC grids is challenging the way the power system has traditionally been modeled. With ever increasing computer performance, the traditional boundary between phasor models and EMT models are fading and it becomes possible to model networks in full detail, thereby not being hindered by the limitations traditionally imposed by phasor programs. However, accounting for very detailed DC systems (not to mention full-detailed MMC converter switching models) still poses a number of stringent limitations to the size of the network. One of the solutions can lie in the application and development of hybrid models, with a detailed EMT representation of the DC network and the AC network in the vicinity of the converter, combined with a standard electromechanical model for the rest of the AC network. Such combined approaches are the subject of ongoing research, and could play an important role in future power system modeling for dynamic AC/DC system interactions.

This paper also addresses two applications in greater detail. First, the connection of offshore wind farms requires a correct representation of the system to provide the necessary services to both the main AC system (e.g. FRT) and the offshore grid. The communication network and its delay is important to include in the model. Secondly, the steady state operation of the power system with HVDC grids is discussed. For the operations it is important to take the multi-zonal multi-stakeholder nature of the power system into account. Depending on who operates, the behavior might change. Moreover, the controllability of the HVDC converter stations allows enhanced security management through the use of preventive and corrective actions. For this, appropriate OPF and SC-OPF tools are under development.

HVDC and HVDC grids introduce additional interactions with the existing systems, which need to be modeled and calculated, requiring new approaches for both the DC and the AC power system. Nevertheless, the fast and controllable HVDC system can help in managing a system with plenty of renewables installed beyond the current limits.

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